Recognized as an
American National Standard (ANSI)

IEEE Loss Evaluation Guide for Power Transformers and Reactors

Circuits and Devices

Communications Technology

Computer

Electromagnetics and Radiation

IEEE Power Engineering Society

Sponsored by the
Transformers Committee

Industrial Applications

Signals and Applications

Standards Coordinating Committees

IEEE Std C57.120-1991

IEEE

Published by the Institute of Electrical and Electronics Engineers, Inc., 345 East 47th Street, New York, NY 10017, USA.

August 12, 1992

SH15511

Recognized as an
American National Standard (ANSI)

IEEE
Std C57.120-1991 (R2000)

IEEE Loss Evaluation Guide for Power Transformers and Reactors

Sponsor

Transformers Committee
of the
IEEE Power Engineering Society

Approved September 16, 1991
IEEE Standards Board

Approved February 28, 1992
American National Standards Institute

Abstract: A method for establishing the dollar value of the electric power needed to supply the losses of a transformer or reactor is provided. Users can use this loss evaluation to determine the relative economic benefit of a high-first-cost, low-loss unit versus one with a lower first cost and higher losses, and to compare the offerings of two or more manufacturers to aid in making the best purchase choice. Manufacturers can use the evaluation to optimize the design and provide the most economical unit to bid and manufacture. The various types of losses are reviewed.
Keywords: economic, loss evaluation, reactors, transformers

The Institute of Electrical and Electronics Engineers, Inc.
345 East 47th Street, New York, NY 10017-2394, USA

ISBN 1-55937-245-1

IEEE Standards documents are developed within the Technical Committees of the IEEE Societies and the Standards Coordinating Committees of the IEEE Standards Board. Members of the committees serve voluntarily and without compensation. They are not necessarily members of the Institute. The standards developed within IEEE represent a consensus of the broad expertise on the subject within the Institute as well as those activities outside of IEEE that have expressed an interest in participating in the development of the standard.

Use of an IEEE Standard is wholly voluntary. The existence of an IEEE Standard does not imply that there are no other ways to produce, test, measure, purchase, market, or provide other goods and services related to the scope of the IEEE Standard. Furthermore, the viewpoint expressed at the time a standard is approved and issued is subject to change brought about through developments in the state of the art and comments received from users of the standard. Every IEEE Standard is subjected to review at least every five years for revision or reaffirmation. When a document is more than five years old and has not been reaffirmed, it is reasonable to conclude that its contents, although still of some value, do not wholly reflect the present state of the art. Users are cautioned to check to determine that they have the latest edition of any IEEE Standard.

Comments for revision of IEEE Standards are welcome from any interested party, regardless of membership affiliation with IEEE. Suggestions for changes in documents should be in the form of a proposed change of text, together with appropriate supporting comments.

Interpretations: Occasionally questions may arise regarding the meaning of portions of standards as they relate to specific applications. When the need for interpretations is brought to the attention of IEEE, the Institute will initiate action to prepare appropriate responses. Since IEEE Standards represent a consensus of all concerned interests, it is important to ensure that any interpretation has also received the concurrence of a balance of interests. For this reason IEEE and the members of its technical committees are not able to provide an instant response to interpretation requests except in those cases where the matter has previously received formal consideration.

Comments on standards and requests for interpretations should be addressed to:

Secretary, IEEE Standards Board
445 Hoes Lane
P.O. Box 1331
Piscataway, NJ 08855-1331
USA

Foreword

(This foreword is not a part of IEEE Std C57.120-1991, IEEE Loss Evaluation Guide for Power Transformers and Reactors.)

The users of power transformers and reactors have become more concerned about the value of losses as the cost of energy and of installing generating capacity has increased. The evaluation of losses has become a very significant part of the purchase decision for some users.

This guide has been written to provide a method of establishing loss evaluation factors for transformers or reactors. With loss evaluation factors, the economic benefit of a high-first-cost, low-loss unit can be compared with a unit with a lower first cost and higher losses. This enables a user to compare the offerings of two or more manufacturers to aid in making the best purchase choice among competing transformers or reactors. Loss evaluation also provides information to establish the optimum time to retire or replace existing units with modern low-loss transformers or reactors.

This guide was prepared by the Transformer Loss Evaluation Working Group of the IEEE West Coast Transformer Subcommittee. The following Working Group members participated in the development of the guide:

Roger Jacobsen, *Chair*

Ray Allustiarti
I. Stephen Benko
Fred Elliot
Dennis Gerlach
Jim Gillies
Thomas Hawkins
Charles Hendrickson
Jess J. Herrera
Charles Hoesel
William Isberg
Herbert Johnson
Robert Kimball
Gary Lindland
Ron Little
George McCrae
Larry Merrifield
Dan Nix
Robert Norton
Samuel Oklu
Denise Roth
Pete Sorensen
Lou Tauber
L. Kay Thompson
Charles Todd

The following persons were on the balloting committee that approved this document for submission to the IEEE Standards Board:

L.C. Aicher
D. J. Allan
B. F. Allen
R. Allustiarti
R. J. Alton
S. J. Antalis
E. H. Arjeski
J. C. Arnold
R. Bancroft
P. L. Bellaschi
S. Bennon
J. J. Bergeron
J. V. Bonnuchi
J. D. Borst
G. H. Bowers
D. J. Cash
E. Chitwood
O. R. Compton
F. W. Cook, Sr.
J. Corkran
D. W. Crofts
M. G. Daniels
D. H. Douglas
J. D. Douglass
J. C. Dutton
J. K. Easley
J. A. Ebert
R. L. Ensign
C. G. Evans
P. P. Falkowski
H. G. Fischer
S. L. Foster
M. Frydman
H. E. Gabel, Jr.
D. A. Gillies
R. L. Grubb
G. Gunnels, Jr.
G. Hall
J. H. Harlow
T. K. Hawkins
F. W. Heinrichs
W. Henning
K. R. Highton
P. J. Hoefler
C. R. Hoesel
R. H. Hollister
C. C. Honey
F. Huber, Jr.
C. Hurty
G. W. Iliff
R. G. Jacobsen
D. C. Johnson
A. J. Jonnatti
C. P. Kappeler
R. B. Kaufman
E. J. Kelly
J. J. Kelly
W. H. Kennedy
A. D. Kline
E. Koenig
J. G. Lackey
H. F. Light
T. G. Lipscomb
R. Little
L. W. Long
R. I. Lowe
M. L. Manning
H. B. Margolis
J. W. Matthews
L. S. McCormick
J. W. McGill
C. J. McMillen
W. J. McNutt
S. P. Mehta
C. K. Miller
C. Millian
R. E. Minkwitz
H. R. Moore
R. J. Musil
W. H. Mutschler
E. T. Norton
B. K. Patel
H. A. Pearce
D. Perco
C. A. Robbins
L. J. Savio
W. E. Saxon
V. Shenoy
B. E. Smith
W. W. Stein
L. R. Stensland
R. B. Stetson
E. G. Strangas
L. Swenson
A. L. Tanton
V. Thenappan
R. C. Thomas
F. W. Thomason
J. A. Thompson
J. P. Traub
D. E. Truax
R. E. Uptegraff
G. Vaillancourt
R. A. Veitch
F. Vogel
L. B. Wagenaar
J. W. Walton
R. J. Whearty
A. Wilks
W. E. Wrenn
A. C. Wurdack
D. A. Yannucci
E. J. Yasuda

The final conditions for approval of this guide were met on September 16, 1991. This guide was conditionally approved by the IEEE Standards Board on February 15, 1990, with the following membership:

Marco W. Migliaro, *Chairman* **Dennis Bodson,** *Past Chairman*
Andrew G. Salem, *Secretary*

Paul L. Borrill
Fletcher J. Buckley
Allen L. Clapp
James M. Daly
Stephen R. Dillon
Donald C. Fleckenstein
Jay Forster*
Thomas L. Hannan
Kenneth D. Hendrix
John W. Horch
Joseph L. Koepfinger*
Michael A. Lawler
Donald J. Loughry
John E. May, Jr.
Lawrence V. McCall
L. Bruce McClung
Donald T. Michael*
Stig Nilsson
Roy T. Oishi
Gary S. Robinson
Terrance R. Whittemore
Donald W. Zipse

*Member Emeritus

Also included are the following nonvoting IEEE Standards Board liaisons:

Fernando Aldana
Satish K. Aggarwal
James Beall
Richard B. Engelman
Stanley Warshaw

Paula M. Kelty
IEEE Standards Department Project Editor

The Accredited Standards Committee on Transformers, Regulators, and Reactors, C57, that reviewed and approved this document, had the following members at the time of approval:

Leo J. Savio, Chair **John A. Gauthier**, Secretary

Organization Represented	*Name of Representative*
Electric Light and Power Group	P. E. Orehek S. M. A. Rizvi F. Stevens J. Sullivan J. C. Thompson M. C. Mingoia *(Alt.)*
Institute of Electrical and Electronics Engineers	J. D. Borst J. Davis J. H. Harlow L. Savio H. D. Smith R. A. Veitch
National Electrical Manufacturers Association	G. D. Coulter P. Dewever J. D. Douglas A. A. Ghafourian K. R. Linsley R. L. Plaster H. Robin R. E. Uptegraff, Jr. P. J. Hopkinson *(Alt.)* J. Nay (Alt.)
Tennessee Valley Authority	F. A. Lewis
Underwriters Laboratories, Inc.	W. T. O'Grady
U.S. Department of Agriculture, REA	J. Bohlk
U.S. Department of Energy, Western Area Power Administration	D. R. Torgerson
U.S. Department of the Interior, Bureau of Reclamation	F. W. Cook, Sr.
U.S. Department of the Navy, Civil Engineering Corps	H. P. Stickley

Contents

IEEE Loss Evaluation Guide for Power Transformers and Reactors

1. Purpose and Scope

The purpose of this guide is to provide a method of establishing the dollar value of the electric power needed to supply the losses of a transformer or reactor. Users can use this loss evaluation to determine the relative economic benefit of a high-first-cost, low-loss unit versus one with a lower first cost and higher losses. Manufacturers can use the evaluation to optimize the design and provide the most economical unit to bid and manufacture. The evaluated cost of losses also enables a user to compare the offerings of two or more manufacturers to aid in making the best purchase choice among competing transformers or reactors. Loss evaluation also provides information to a user for establishing the optimum time to retire or replace existing units with modern low-loss transformers or reactors.

The user should determine, on a dollars-per-kilowatt basis, the sum of the present worth of each kilowatt of losses of a transformer throughout its life, or some other selected period of time. This figure represents the maximum amount that can be spent to save a kilowatt of loss. A portion of this evaluated cost can be paid to the manufacturer to reduce losses. However, this evaluated cost includes other costs associated with owning a more expensive piece of equipment, such as financing costs, taxes, etc.

This guide provides formulas by which the costs of energy, power, and money, and the loading pattern of a transformer can be converted to dollars-per-kilowatt values of the transformer losses.

These dollars-per-kilowatt figures should be furnished to the manufacturer when bids are requested. If the final tested values of losses vary from the manufacturer's guaranteed values, economic adjustments may be made.

Nothing in this guide is mandatory. It should not be inferred from this paper that the methodology described in the following pages is the only valid methodology for computing the cost of transformer losses. Many users have developed their own transformer loss evaluation techniques that are suitable for the intended purpose. The list of terms in Section 2 uses symbols selected for mnemonic effectiveness and might be different from symbols used in other references.

2. List of Terms Applicable to Transformer Loss Evaluation Equations

Term	Unit	Symbol	Text Reference
Auxiliary loss cost rate of stage one cooling equipment	$/kW	ALCR1	6.2.3.1
Auxiliary loss cost rate of stage two cooling equipment	$/kW	ALCR2	6.2.3.2
Auxiliary power lost in stage one cooling equipment	kW	APL1	5.5
Auxiliary power lost in stage two cooling equipment	kW	APL2	5.5
Auxiliary power loss	kW	APL	5.5
Availability factor	—	AF	6.1.2
Average hours per year for stage one cooling alone	hours (h)	AHPY1	5.5
Average hours per year for stage two cooling equipment	hours (h)	AHPY2	5.5
Booklife	years	BL	Section 4
Capital recovery factor	—	CRF	6.1.7
Carrying charge (see fixed charge rate)			
Current year energy cost	$/kWh	CYEC	App. B
Efficiency of transmission	—	ET	6.1.1
Energy cost inflation rate	per year	EIR	A1.
Fixed charge rate (generator)	$/$/yr	FCRG	6.1.6
Fixed charge rate (transformer)	$/$/yr	FCRT	6.1.6
Fixed charge rate (transmission systems)	$/$/yr	FCRS	6.1.6
Generation installation cost	$/kW	GIC	6.1.9
Increase factor	—	IF	6.1.8
Levelized auxiliary energy cost for stage one	$/kW-yr	LAEC1	6.1.11

Term	Unit	Symbol	Reference
Levelized auxiliary energy cost for stage two	$/kW-yr	LAEC2	6.1.12
Levelized energy and operating cost	$/kW-yr	LECN LECL	6.1.10 6.1.10
Levelized generation investment cost	$/kW-yr	LGIC	6.1.9
Levelized total system investment cost	$/kW-yr	LIC	6.1.9
Levelized transmission system investment cost	$/kW-yr	LSIC	6.1.9
Load Loss (copper or conductor loss)	kW	LL	5.4
Load loss cost rate	$/kW	LLCR	6.2.2
No-load loss (iron or core loss)	kW	NLL	5.3
No-load loss cost rate	$/kW	NLLCR	6.2.1
Number of years	years	N	6.1.7
Peak-per-unit load	—	PUL	6.1.4
Peak responsibility factor	—	PRF	6.1.3
Present worth energy and operating cost	$/kWh	PWEC	6.1.10
Rate of return	per year	ROR	6.1.7
Sum of present worth — energy and operating cost	$/kWh booklife or $/kW-yr booklife	SPWECH SPWECY	6.1.10 6.1.10
Transformer loading factor	—	TLF	6.1.5
Transmission system installation cost	$/kW	SIC	6.1.9

3. Definitions

For further explanation of the following terms, see Sections 5 and 6. For definitions not found in this guide, consult IEEE Std 100-1988 [B3].[1]

auxiliary power losses (APL). The power required for cooling fans, oil pumps, and other ancillary equipment.

[1] The numbers in brackets correspond to those of the Bibliography in Section 7.

availability factor (AF). The proportion of time that a transformer is predicted to be energized.

capital recovery factor (CRF). The factor used to determine total levelized annual costs.

core loss. The power dissipated in a magnetic core subjected to a time-varying magnetizing force.

efficiency of transmission (ET). The energy received at the input terminals of the transformer divided by the energy transmitted from the source.

fixed charge rate or carrying charge rate (FCRG for generators, FCRS for transmission systems, and FCRT for transformers). The levelized annual cost divided by the cost of investment.

increase factor (IF). The factor representing the total that the user must pay to acquire the transformer, including the purchase price, overhead, fee, tax, etc., *based on its value.*

levelized auxiliary energy cost for stage one (LAEC1). The sum of the present worth of energy and operating costs in dollars-per-kilowatthour booklife (SPWECH) is multiplied by the total number of hours per year that stage one cooling is expected to be operating, to get the sum of the present worth of energy and operating cost in dollars-per-kilowatt-year booklife (SPWECY1).

levelized auxiliary energy cost for stage two (LAEC2). The sum of the present worth of energy and operating cost in dollars-per-kilowatthour booklife (SPWECH) is multiplied by the total number of hours per year that stage two cooling is expected to be operating, to get the sum of the present worth of energy and operating cost in dollars-per-kilowatt-year booklife (SPWECY2).

levelized energy cost (LECN for no-load loss evaluation, and LECL for load loss evaluation). The cost of energy and operation is expressed in dollars per kilowatt-year.

levelized total system investment cost (LIC). The annual cost, in dollars per kilowatt-year, of the additional generation and transmission system capacity needed to supply the power used by the losses, including the cost of financing that investment.

load losses (LL). Those losses that are incident to the carrying of a specified load.

no-load (excitation) losses (NLL). Those losses that are incident to the excitation of the transformer.

peak-per-unit load (PUL). The average of yearly peaks over the lifetime of the transformer, or some other load growth cycle,[2] divided by the rating at which the load losses are guaranteed and tested.

peak responsibility factor (PRF). The power transformer's load at the time of the system peak divided by the power transformer's peak load.

total power losses. The sum of the no-load losses and the load losses, not including auxiliary losses.

transformer loading factor (TLF). The root-mean-square value of the predicted loads of the power transformer over a representative yearly period is an equivalent load.

---

[2] A load growth cycle may be, for instance, the time between the initial loading and when the planned loading limit of the transformer is reached.

4. Basic Concept

The basic concept of this guide is that the evaluation for each type of loss (no-load, load, and auxiliary) is the sum of (1) the demand portion, and (2) the energy portion.

(1) The demand portion is the cost of installing system capacity in dollars per kilowatt, and
(2) The energy portion is the present value of the energy that will be used by one kilowatt of loss during the booklife of the transformer, converted to dollars per kilowatt.

For convenience in adding like terms, the values are levelized, that is, converted to yearly values, and then the sum is divided by the fixed charge rate for transformers and any other appropriate factors, to give equivalent values that can be used directly by the manufacturer in designing and pricing the transformer, and later by the user in comparing bids. Fixed charge rates are the "cost of ownership," and have the dimensions of dollars-per-dollar-per-year, or simply per-year. The units are satisfied in the following basic equation:

$$\text{the loss cost rate} = \frac{\overset{\text{Yearly Cost of}}{\underline{\text{Demand Portion}}}\left[\begin{matrix}\text{cost of}\\ \text{installing}\\ \text{a kilowatt}\\ \text{of plant}\end{matrix}\times\begin{matrix}\text{fixed}\\ \text{charge}\\ \text{rate of}\\ \text{plant}\end{matrix}\right]+\overset{\text{Yearly Cost of}}{\underline{\text{Energy Portion}}}\left[\begin{matrix}\text{cost of a}\\ \text{kilowatthour}\end{matrix}\times\begin{matrix}\text{hours per}\\ \text{year that}\\ \text{transformer}\\ \text{is energized}\end{matrix}\right]}{\left(\begin{matrix}\text{fixed charge rate}\\ \text{for transformers}\end{matrix}\right)} \quad \text{(Eq 1)}$$

The numerator of the above formula shows how much it will cost per year to provide a continuous kilowatt. The denominator is the fixed charge rate for transformers. The numerator divided by the denominator determines how much a user can afford to pay for a more efficient transformer to save that kilowatt.

$$\frac{\left(\frac{\$}{\text{kW}}\times\frac{\frac{\$}{\$}}{\text{yr}}\right)+\left(\frac{\$}{\text{kWh}}\times\frac{\text{h}}{\text{yr}}\right)}{\frac{\frac{\$}{\$}}{\text{yr}}} = \frac{\left(\frac{\$}{\text{kW}}\times\frac{1}{\text{yr}}\right)+\left(\frac{\$}{\text{kW}}\times\frac{1}{\text{yr}}\right)}{\frac{1}{\text{yr}}} =$$

$$\left(\frac{\$}{\text{kWyr}}+\frac{\$}{\text{kWyr}}\right)\times\text{yr} = \frac{\$}{\text{kW}}+\frac{\$}{\text{kW}}=\frac{\$}{\text{kW}} \quad \text{(Eq 2)}$$

NOTE: Dimensionless factors, such as transmission efficiency, tax rate, transformer loading factor, peak-per-unit load, and peak responsibility factor, may also be involved.

5. Description of Transformer and Reactor Power Losses

5.1 Transformers. The losses in a transformer are basically of two types: *no-load* losses, which occur simply because the transformer is energized; and *load* losses, which vary with the transformer's loading. In addition, auxiliary power is required by fans, pumps, heaters, and other ancillary equipment. This auxiliary power is not necessarily

dependent upon the load. All losses and auxiliary power requirements, as discussed in this guide, are expressed in kilowatts.

5.2 Reactors

5.2.1 Shunt Reactors. A shunt reactor acts as a constant load at a given voltage. Its total loss cost evaluation (even though consisting mainly of I^2R losses) is calculated using only the *no load loss* formula in 6.2.1 (Eq 7). Its losses increase as the impressed voltage increases.

5.2.2 Series Reactors. A series reactor experiences a varying load. Because it does not have a no-load loss, its total power loss cost evaluation is calculated using only the *load loss* formula in 6.2.2 (Eq 8).

5.3 No-Load (Excitation) Losses (NLL). Those losses that are incident to the excitation of the transformer. No-load (excitation) losses include dielectric loss, conductor loss in the winding due to exciting current, conductor loss due to circulating current in parallel windings, and core loss. Core loss is the power dissipated in a magnetic core subjected to a time-varying magnetizing force. Core loss includes hysteresis and eddy current losses of the core. These losses change with the excitation voltage, and may increase sharply if the rated voltage of the transformer is exceeded. The no-load losses also increase as the temperature of the core decreases.When transformer no-load losses are compared, the same reference temperature should be used.

5.4 Load Losses (LL). Those losses that are incident to the carrying of a specified load. Load losses include I^2R loss in the winding due to load and eddy currents, stray loss due to leakage fluxes in the windings, core clamps, and other parts, and the loss due to circulating currents (if any) in parallel windings or in parallel winding strands. These losses are often referred to as "copper losses," although the actual winding may be of some other material, such as aluminum. These losses vary with the square of the load. The losses also vary with the absolute temperature of the windings. For comparative purposes, load loss values are given at a reference load and at reference winding temperature. It is important that these reference values be stated whenever loss values are given.

NOTE: The rating upon which the load losses are based usually refers to the self-cooled rating of the transformer (for those transformers that have a self-cooled rating), based on cooling class and temperature rise, and not to the extended ratings available with auxiliary cooling. For example, 12/16/20 MVA transformers having a self-cooled rating of 12 MVA usually have load losses tested at 12 MVA. When carrying 20 MVA, the load losses would be approximately 2.78, i.e., $(20/12)^2$ times the tested losses. In addition, the extended loading would call for fans and pumps to be running, which require additional power as listed in 5.5.

For an FOA or FOW transformer, the losses are measured at the FOA or FOW rating, or other agreed upon ratings.

Any rating may be used to evaluate load losses (even one that may not be shown on the nameplate), so long as the manufacturer knows in advance, for optimizing the design and the test results are appropriately shown on the test report.

5.5 Auxiliary Power Losses (APL). The power required for cooling fans, oil pumps, and other ancillary equipment. All of these power requirements are expressed in kilowatts. If two or more separate stages of cooling are used, these should be expressed in separate parts, APL1, APL2, etc., because the individual stages will be used for different amounts of time. The number of hour per year for each stage of cooling, AHPY1, AHPY2, etc., will need to be estimated in order to calculate a value for the energy for each stage. It should be kept in mind that generally stage one cooling is also running whenever stage two is on.

NOTES:
(1) The above three loss values: NLL, LL, and APL, are normally stated by the manufacturer with his bid, and later determined by actual tests.
(2) For power transformers used in HVDC converter stations, additional considerations are necessary for losses incurred by harmonic currents. These harmonic losses are not discussed in this guide.

5.6 Total Power Losses. Defined by IEEE C57.12.00-1987 [B4], subsection 5.9, these losses are the sum of the no-load losses and the load losses, and do not include auxiliary losses. For purposes of economic evaluation, however, the user should consider no-load, load, and auxiliary power losses. Care should be taken not to use the term *total load loss*, as the reader will not know whether *load loss* or *total loss* is meant.

In addition to kilowatt losses, there also exists a kilovar consumption. However, the cost of providing the kilovar consumption is typically not evaluated. Only real power losses are considered in this guide. However, if the kilovar consumption were to be evaluated, the cost per kvar of installing capacitors might be used as a basis of evaluation.

NOTE: The losses in load tapchanging (LTC) transformers vary with the LTC position. In addition, at any given position, the losses may vary with different configurations of LTC equipment, such as tap winding location, the presence of series transformers, preventive autotransformers, etc. The user should consider these variations when comparing two or more offerings.

6. Cost Evaluation Methodology

6.1 Explanation of Factors

NOTE: In this guide, base and peak costs are used as if they were the same. If they are not the same, the user should determine the relative cost and the complex interrelationship of each, for no-load and load losses.

The determination of the cost of transformer losses involves many loss cost factors, some of which must be estimated. The user is advised to pay particular attention to the number of significant figures in the data and the assumed economic values, and to be consistent in the application of these significant digits in the calculations. There is little justification in using assumed values with two-place accuracy to calculate the cost of losses to four or more places. The factors that are used to develop the power loss cost rates for no-load losses, load losses, and auxiliary losses are defined in the following subsections:

6.1.1 Efficiency of Transmission (ET). The energy received at the input terminals of the transformer divided by the energy transmitted from the source. The efficiency will vary seasonally, or by loading, location, or voltage level, but unless this variation is unusually large for a particular instance, a general overall system efficiency will probably be adequate for this factor. Also, the capacity and the energy portions of the loss equations may have differing efficiency values applied to them, but here again, in most cases, one overall system efficiency factor will probably be adequate.

(If different values were to be used, then Eq 7 (6.2.1), for instance, might become the following:

$$\mathrm{NLLCR} = \frac{\mathrm{LIC}}{(\mathrm{ET_C})(\mathrm{FCRT})(\mathrm{IF})} + \frac{\mathrm{LECN}}{(\mathrm{ET_E})(\mathrm{FCRT})(\mathrm{IF})} \qquad \text{(Eq 3)}$$

where $\mathrm{ET_C}$ = efficiency for capacity, and $\mathrm{ET_E}$ = efficiency for energy.)

6.1.2 Availability Factor (AF). The proportion of time that a transformer is predicted to be energized. This factor is significant in connection with the energy cost of the losses.

6.1.3 Peak Responsibility Factor (PRF). The power transformer's load at the time of the system peak divided by the power transformer's peak load. The portion of the system's capability allocated to meet this transformer's losses varies as the square of this ratio.

6.1.4 Peak-Per-Unit Load (PUL). The average of the yearly peaks over the lifetime of the transformer, or some other load growth cycle,[3] divided by the rating at which the load losses are guaranteed and tested. The demand portion of load loss cost rate will vary as the square of this ratio.

NOTE: The above definition gives an approximation that is consistent with the accuracy of most *estimated, future*, peak loading values. If the transformer is planned to be loaded to a compound or a linear load growth rate, then PUL can be determined by using other methods. One such method is given on pp. 790–91 in Nickel and Braunstein [B7].

6.1.5 Transformer Loading Factor (TLF). The root-mean-square value of the predicted loads of the power transformer over a representative yearly period is an equivalent load. This equivalent load, in MVA, divided by the rating at which the load losses are guaranteed and tested, yields an equivalent load in per unit, which is referred to in this guide as the transformer loading factor (TLF).

The energy cost of the load losses will vary as the square of this factor. The equivalent load, if applied uniformly 8760 hours of one year, would produce the same amount of load losses as that produced in the transformer by the actual load current during a given year. Equivalent load is discussed in IEEE C57.92-1981 [B6], where it is defined as the constant load that generates losses at the same rate as the average rate caused by the fluctuating load.

If the representative yearly loss factor is known, a generally easier way to find $(\mathrm{TLF})^2$ is by the following formula (keeping in mind that the loss factor must be based on 8760 hours of a representative yearly period, the same as the basis for TLF):

$$(\mathrm{TLF})^2 = \text{loss factor} \times (\mathrm{PUL})^2 \qquad \text{(Eq 4)}$$

6.1.6 Fixed Charge Rate or Carrying Charge Rate (FCRG for Generators, FCRS for Transmission Systems, and FCRT for Transformers). The levelized annual cost divided by the cost of investment. The fixed charge rate represents the "cost of ownership." The costs are fixed inasmuch as they do not depend on system kilowatthours sold. The use of this rate shows the income (savings) per year necessary to support a capital investment. Some of the components of cost in the fixed charge rate, expressed as a proportion of investment, are as follows:

(1) Minimum acceptable rate of return;
(2) Annual cost of depreciation;
(3) Levelized federal and state income tax; and
(4) Annual cost of property taxes and insurance.

NOTE: The fixed charge rate for transformers is used in the denominator of the loss cost rate formulas (see 6.2.1, 6.2.2, 6.2.3). A high fixed charge rate will result in a low dollars-per-kilowatt evaluation, and a low fixed charge rate will result in a high evaluation. The formulas are only meaningful for realistic values of fixed charge rate. Users who buy transformers with some form of financing that does not include interest, depreciation, taxes, insurance, etc., cannot use the formulas given in this guide.

6.1.7 Capital Recovery Factor (CRF). The factor used to determine "total levelized annual costs." The sum of the present worth of the costs is levelized by multiplying by the capital recovery factor.

---

[3] See Footnote 2.

$$CRF = \frac{ROR\ (1+ROR)^N}{(1+ROR)^N - 1} \qquad \text{(Eq 5)}$$

where

CRF = the capital recovery factor, expressed in units
ROR = the rate of return
N = the number of years the costs are to be levelized

6.1.8 Increase Factor (IF). The factor representing the total that the user must pay to acquire the transformer, including the purchase price, overhead, fee, tax, etc., *based on its value*.

The loss evaluation figures supplied to the manufacturers at the time of soliciting bids should be reduced appropriately, below the actual value of a kilowatt of power. Internally imposed, in-house overheads may not apply here, depending upon user practices.

Examples of applicable cost increase factor are the following:

- Sales tax
- Architect-Engineer's fee
- Construction supervision fee
- Contractor's fee
- Job order fee (imposed by outside organization)
- Interest during construction
- Extended warranty and transportation insurance, if these can be uniformly applied to all bidders

Examples of possible applicable cost increase factor are the following:

- General overhead
- Stores charges

All of the applicable rates in per unit are added to 1.0, and the resulting value is used in the denominator of the loss cost rate formulas in 6.2.1, 6.2.2, and 6.2.3.

Example:

• Sales tax	8%
• Architect-Engineer's fee	10%
• Transportation insurance	1%
• Interest during construction	2% (2 months @ 12% per annum)

Increase factor = 1.00 + 0.08 + 0.10 + 0.01 + 0.02 = 1.21

6.1.9 Levelized Total System Investment Cost (LIC).[4] The annual cost, in dollars per kilowatt-year, of the additional generation and transmission system capacity needed to supply the power used by the losses, including the cost of financing that investment.

[4] The discussion in this paragraph is applicable to users who own their generation and/or transmission facilities. Many users who do not own those facilities pay a demand charge. This demand charge can be converted to LIC by multiplying by a suitable factor. For example, if the demand charge is levied in dollars per kilowatt per month, it can be multiplied by 12 to give the value of LIC in dollars per kilowatt-year.

NOTE: The concept of levelization is described in Appendix A. The levelized total system investment cost (LIC) is computed as follows:

$$LIC = (GIC)(FCRG) + (SIC)(FCRS) \quad \text{(Eq 6)}$$

where

GIC = the cost of installing generation, expressed in dollars per kilowatt
SIC = cost of installing transmission systems, expressed in dollars per kilowatt
FCRG = the fixed charge rate for generation
FCRS = the fixed charge rate for the transmission system
(GIC)(FCRG) = LGIC, the levelized generation investment cost
(SIC)(FCRS) = LSIC, the levelized transmission system investment cost

6.1.10 Levelized Energy Cost (LECN for No-Load Loss Evaluation, and LECL for Load Loss Evaluation). The cost of energy and operation is expressed in dollars per kilowatt-year. This cost is computed by using the following method to obtain a present worth value:

(1) List the projected cost of energy in dollars per kilowatthour for each year being considered.
(2) Discount these annual inflated energy costs by the appropriate present worth factor, at the user's rate of return, for each year being considered (see Appendix A), to get the present worth value of each year's energy and operating cost in dollars per kilowatt-year (PWEC).
(3) Add each of the present worth values, for all of the years being considered, to get the sum of the present worth of energy and operating cost in dollars-per-kilowatthour booklife (SPWECH).
(4) Multiply SPWECH, the sum of the present worth of energy and operating cost in dollars per kilowatthour by 8760 hours per year (or the number of hours the transformer is expected to be energized per year *or* 8760 times the availability factor), to get SPWECY, the sum of the present worth of energy and operating cost in dollars-per-kilowatt-year booklife for the operation of the transformer.

Determine the capital recovery factor (CRF) by Eq 5 (6.1.7).

Multiply SPWECY by CRF to get LECN, the levelized annual energy and operating cost of no-load losses in dollars per kilowatt-year for the operation of the transformer.

NOTE: The calculation covered here by (4) yields the levelized annual energy and operating cost of *no-load* losses. When finding the levelized annual energy and operating cost of *load* losses, SPWECH in (4) should be multiplied by 8760 h/yr to get SPWECY.

In calculating LECL, it is not appropriate to use a reduced number of hours per year, because the transformer loading factor takes this into account.

See Appendix B for example calculations.

6.1.11 Levelized Auxiliary Energy Cost for Stage One (LAEC1). The sum of the present worth of energy and operating costs in dollars-per-kilowatthour booklife (SPWECH) is multiplied by the total number of hours per year that stage one cooling is expected to be operating, to get the sum of the present worth of energy and operating cost in dollars-per-kilowatt-year booklife (SPWECY1). (Note that stage one cooling is also operating whenever stage two cooling is operating.) SPWECY1 is then multiplied by the capital recovery factor (CRF) to get the levelized annual energy and operating costs for stage one cooling (LAEC1), in dollars per kilowatt-year.

6.1.12 Levelized Auxiliary Energy Cost for Stage Two (LAEC2). The sum of the present worth of energy and operating cost in dollars-per-kilowatthour booklife (SPWECH) is multiplied by the total number of hours per year that stage two cooling is expected to be operating, to get the sum of the present worth of energy and operating cost in dollars-per-kilowatt-year booklife (SPWECY2).

SPWECY2 is then multiplied by the capital recovery factor (CRF) to get the levelized annual present worth of energy and operating cost for stage two cooling (LAEC2), in dollars per kilowatt-year.

6.1.13 FOA, FOW Cooling Methods. The discussions in 6.1.11 and 6.1.12 are based on a triple-rated transformer. A similar evaluation can be made for FOA and FOW transformers using the number of hours per year that each fan or pump is expected to run. Equipment that runs continuously will be evaluated the same as the no-load losses.

6.2 Loss Cost Rate Formulas. Loss cost rate formulas are developed for no-load losses, load losses, and auxiliary losses. The results of these formulas—loss cost rates—are supplied to the manufacturer at the time of requesting bids. The cost rates in dollars per kilowatt, multiplied by their respective guaranteed losses in kilowatts, can be added directly to the bid price in the evaluation of purchase alternatives.

The loss cost rate formulas represent the cost of installing generation and transmission to supply the demand represented by one kilowatt of transformer loss, and the cost of producing the energy consumed by that loss.

The loss cost rate formulas are computed in the following manner:

6.2.1 No-Load Power Loss Cost Rate (NLLCR)

$$\text{NLLCR} = \frac{\text{yearly cost of demand portion} + \text{yearly cost of energy portion}}{\text{fixed charge rate for transformers} \times \text{efficiency and tax, etc., factors}}$$

$$\text{NLLCR} = \frac{\text{LIC} + \text{LECN}}{(\text{ET})(\text{FCRT})(\text{IF})} \qquad \text{(Eq 7)}$$

where

NLLCR = the equivalent no-load loss cost rate in dollars per kilowatt. This is the value of no-load power losses that the user should furnish to the manufacturers at the time of soliciting bids.

LIC = the levelized annual total system investment cost in dollars per kilowatt-year

LECN = the levelized annual energy and operating cost of no-load losses, expressed in dollars per kilowatt-year

ET = the efficiency of transmission

FCRT = the fixed charge rate for transformers

IF = the increase factor

6.2.2 Load Power Loss Cost Rate (LLCR)

$$\text{LLCR} = \frac{\text{yearly cost of demand portion} + \text{yearly cost of energy portion}}{\begin{array}{c}\text{fixed charge rate for transformers} \times \text{efficiency and tax, etc., factors,}\\ \text{and as modified by the loading factors squared}\end{array}}$$

$$\text{LLCR} = \frac{(\text{LIC})(\text{PRF})^2(\text{PUL})^2 + (\text{LECL})(\text{TLF})^2}{(\text{ET})(\text{FCRT})(\text{IF})} \qquad \text{(Eq 8)}$$

where

LLCR = the equivalent load loss cost rate, in dollars per kilowatt. This is the value of load power losses that the user should furnish to the manufacturers at the time of soliciting bids.
LIC = the levelized annual total system investment cost in dollars per kilowatt-year
PRF = the peak responsibility factor
PUL = the peak-per-unit load
TLF = the transformer loading factor
LECL = the levelized annual energy and operating cost of load losses, expressed in dollars per kilowatt-year
ET = the efficiency of transmission
FCRT = the fixed charge rate for transformers
IF = the increase factor

6.2.3 Auxiliary Power Loss Cost Rates

6.2.3.1 Auxiliary Loss Cost Rate for Stage One (ALCR1)

$$ALCR1 = \frac{LIC + LAEC1}{(ET)(FCRT)(IF)} \qquad \text{(Eq 9)}$$

where

ALCR1 = the rate of the auxiliary power costs related to stage one cooling, expressed in dollars per kilowatt
LIC = the levelized annual total system investment cost expressed in dollars per kilowatt-year
LAEC1 = the levelized annual energy and operating cost for stage one, expressed in dollars per kilowatt-year
ET = the efficiency of transmission
FCRT = the fixed charge rate for transformers

6.2.3.2 Auxiliary Loss Cost Rate for Stage Two (ALCR2)

$$ALCR2 = \frac{LIC + LAEC2}{(ET)(FCRT)(IF)} \qquad \text{(Eq 10)}$$

where

ALCR2 = the rate of the auxiliary power costs related to stage two cooling, expressed in dollars per kilowatt
LIC = the levelized annual total system investment cost, expressed in dollars per kilowatt-year
LAEC2 = the levelized annual energy and operating cost for stage two, expressed in dollars per kilowatt-year
ET = the efficiency of transmission
FCRT = the fixed charge rate for transformers
IF = the increase factor

6.3 Use of Power Loss Cost Rates. Following are some of the ways in which transformer loss cost rates can be used:

(1) By manufacturers, to design and build efficient, cost-effective transformers.
(2) By users, to choose between two or more offerings.
(3) By owners, to decide whether or not to replace existing units with new, more efficient equipment, or to build new systems to eliminate double transformations, etc.

The loss cost rates, in dollars per kilowatt, for no-load, load, and auxiliary losses, as found in 6.2.1, 6.2.2 and 6.2.3, respectively, are the figures that should be furnished to the manufacturers at the time of soliciting bids.

The manufacturer may utilize the cost rate values to build a transformer that has amounts of conductor and iron that are economically dictated by the dollar evaluation.

That is, the manufacturer may reduce losses, by adding conductor and iron up to an amount where the incremental construction costs of adding conductor and iron equal the incremental value of the transformer.

The rates should be preferably furnished to the manufacturers in the dollars-per-kilowatt form as discussed above. They may also be given in the levelized annual form of dollars-per-kilowatt-year, but if they are so given, it will be necessary also to supply the manufacturer with information as to the purchaser's fixed charge rate, sales tax rate, overheads, etc., and to rely on the manufacturer to make the proper calculations. Use of the dollars-per-kilowatt form will ensure that each manufacturer is using the same basis for optimizing the design.

In order to compare two or more bids, add the following products to the bid price (for each separate bid):

(1) The manufacturer's guaranteed no-load losses in kilowatts, times the dollars-per-kilowatt figure for NLLCR.
(2) The manufacturer's guaranteed load losses in kilowatts, times the dollars-per-kilowatt figure for LLCR.
(3) The manufacturer's guaranteed losses for each type of auxiliary loss, times the appropriate dollars-per-kilowatt figures for ALCR1, ALCR2, etc.

When all of these are added to the bid price, the lowest resulting figure indicates the "best buy," provided, of course, that the offered transformers are comparable in other respects.

If loss evaluation figures are furnished to the manufacturers at the time of soliciting bids, the steps outlined above should be used to select the best offering. A selection based only on bid price will not necessarily represent the true value of the offered equipment.

7. Bibliography

[B1] Electrical Power Research Institute, "Technical Assessment Guide," PS-1201-SR, Special Report, July 1979.

[B2] Grant, Eugene L., *Principles of Engineering Economy*, 6th ed., Ronald Press Company, 1976.

[B3] IEEE Std 100-1988, IEEE Standard Dictionary of Electrical and Electronics Terms (ANSI).

[B4] IEEE C57.12.00-1987, IEEE Standard General Requirements for Liquid-Immersed Distribution, Power, and Regulating Transformers (ANSI).

[B5] IEEE C57.12.80-1978 (Reaff 1986), IEEE Standard Terminology for Power and Distribution Transformers (ANSI).

[B6] IEEE C57.92-1981 (Reaff 1991), IEEE Guide for Loading Mineral-Oil-Immersed Power Transformers up to and Including 100 MVA with 55 °C or 65 °C Winding Rise (ANSI).

[B7] Nickel, D. L. and H. R. Braunstein, "Distribution Transformer Loss Evaluation—Part 1: Proposed Techniques," pp. 788–97, and "Distribution Transformer Loss Evaluation—Part 2: Load Characteristics and System Cost Parameters," pp. 798–811, *IEEE Transactions on Power Apparatus and Systems*, Vol. PAS-100, No. 2.

IEEE

Appendixes

(These appendixes are not part of IEEE Std C57.120-1991, but are included for information only.)

Appendix A
Levelized Energy Costs

The energy costs utilized in the no-load loss, load loss, and auxiliary loss power cost formulas represent present worth values that have been levelized (see 6.1.10, 6.1.11, and 6.1.12). This appendix describes the concept of a present worth value and the concept of levelization.

A1. Present Worth Value

An understanding of the procedure of inflating, discounting, and summing may be gained by development of the following ten-year present worth value table. The procedure involves the escalation of energy costs by year at a constant rate over a selected period of time—ten years in this example. In actuality, the time frame may be selected to be consistent with the booklife of the transformer and variable inflation rates may be employed.

To introduce the concept of present worth value, Table A1 uses a constant 5% energy cost inflation rate. Each year's inflated energy cost is discounted by the appropriate present worth factor and then summed to a total present worth energy cost for the entire time period. The discount factor is defined as the user's required rate of return.

Present worth value calculations are described as follows:

A1.1 Escalated Value. The escalated value equation, $F = P(1 + i)^N$, may be utilized in order to escalate a present value *(P)*, to a future value *(F)*, in a future year *(N)*, for a given escalation rate *(i)*. For a 5% escalation, the following year's average escalated energy value is as follows:

$$F=P(1 + .05)^1$$

Example:

Using a 5% escalation rate, the energy value five years from a current year's energy value of .051 \$/kWh is computed as follows:

$$F = .051(1.05)^5 = .065 \text{ \$/kWh}$$

A1.2 Present Worth Value. The present worth calculation utilizes the inverse of the escalation formula. The present worth equation, $P = F(1 + r)^{-N}$, may be utilized in order to calculate the present worth *(P)*, from a future value *(F)*, from a future year *(N)*, for a given discount rate *(r)*.

Example:

Using a 16% discount rate or rate of return, the current present worth value of the cost of energy of .068 \$/kWh six years in the future is computed as follows:

$$P=.068(1 + .16)^{-6} = .0279 \text{ \$/kWh}$$

A present worth table may be computed utilizing $(1 + r)^{-N}$. Table A1 results from applying a 16% rate of return to obtain the present worth factor per year over a ten-year period $((1 + .16)^{-N})$.

Table A1
Ten-Year Present Worth Value Table

Year	I	II	III	IV	V	VI	VII	VIII	IX	X
Present Worth Factor	.862	.743	.641	.552	.476	.410	.354	.305	.263	.227

An example of energy cost of $0.051/kWh escalated at a 5% rate over a ten-year period and brought back to a present worth value is as follows:

Row	At End of Year	I	II	III	IV	V	VI	VII	VIII	IX	X
A	Cost of Energy	.054	.056	.059	.062	.065	.068	.072	.075	.079	.083
B	Present Worth Factor	.862	.743	.641	.552	.476	.410	.354	.305	.263	.227
C	Present Worth Value	.047	.042	.038	.034	.031	.027	.025	.023	.021	.019
D	The Sum of Present Worth Values = 0.307 $/kWh										

NOTE: The levelized energy cost in dollars per kilowatthour equals 0.307 times the capital recovery factor.

levelized energy cost = $0.307 × CRF = $0.307 × 0.207 = $0.064

(See explanation of this step in the following paragraphs.)

Row A of Table A1 shows the escalated cost of energy in dollars per kilowatthour over a ten-year period. The cost of energy is assumed to grow at a 5% annual rate from year one to year ten. The cost of energy is multiplied by the present worth factor (Row B) in order to arrive at the present value of energy costs on a yearly basis (Row C). The present worth values per year are summed over the entire ten-year period in order to arrive at the sum of present worth values of the escalated energy costs for the selected time frame. The sum of present worth values = 0.307 (Row D).

The capital recovery factor is calculated by using Eq 5 (6.1.7) as follows:

$$\mathrm{CRF} = \frac{(0.16)(1.16)^{10}}{(1.16)^{10} - 1} = 0.207$$

The sum of the present worth energy and operating cost is multiplied by the capital recovery factor (CRF) in order to compute the levelized energy cost (Row E).

$0.064/kWh is then multiplied by the number of hours per year that the transformer will be energized, to yield the levelized annual cost of energy in dollars per kilowatt-year.

A2. Levelization

The concept of levelization is illustrated in Fig A1.

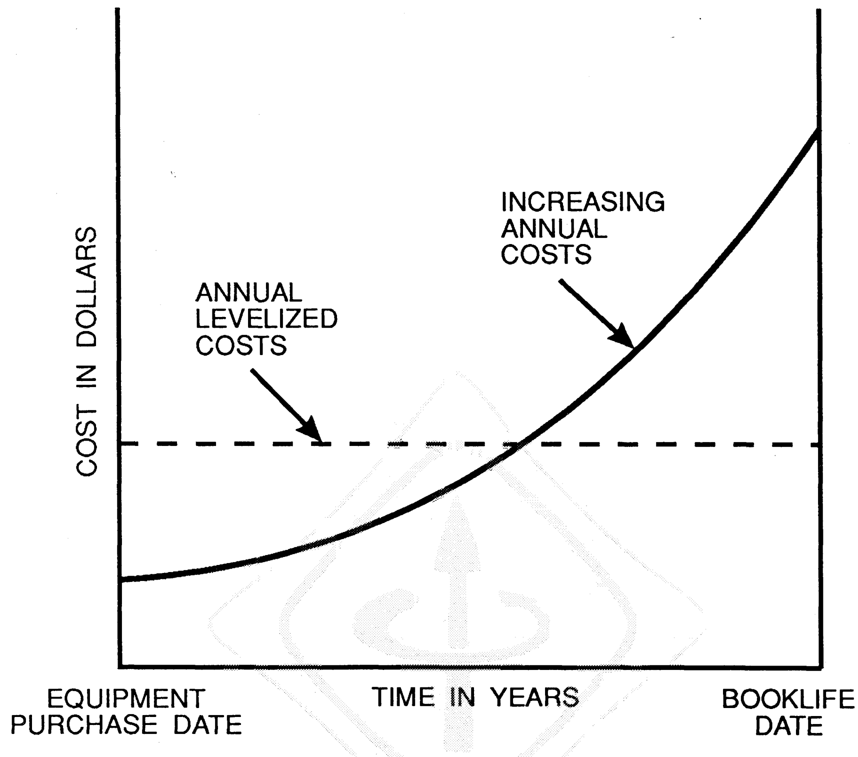

Fig A1
Illustration of Levelization

The solid line in the graph above represents increasing annual costs from time of equipment purchase to the last year of the equipment booklife. The procedure of levelization takes the present worth value of this increasing stream of energy costs and spreads this "lump sum" present worth value equally over the years of the equipment's booklife.

The dotted line in the graph represents the levelized energy costs. In this guide, energy costs are levelized on an annual basis. Levelization is accomplished by multiplying the sum of the present worth values by the capital recovery factor. The levelized energy cost is an input variable in the equations for the cost rates of no-load, load, and auxiliary power losses as described in 6.2.1, 6.2.2, and 6.2.3.

A3. Variable Inflation Rate Formula

When annual energy inflation rates are not constant over the evaluation time period, each year's present worth factor may be calculated and summed. The example calculation below shows the calculation of the present worth of energy cost for a three-year time period.

Given that the energy cost inflation rate is 6% in year one, 4% in year two, and 2% in year three, the rate of return is 16%, and the current-year energy cost is .03 $/kWh, the present worth energy calculation is as follows:

Year 1: $$\frac{(1+.06)^1}{(1+.16)^1}=\frac{1.06}{1.16}=.914$$

Year 2: $$\frac{(1+.06)(1+.04)}{(1+.16)^2}=.819$$

Year 3: $$\frac{(1+.06)(1+.04)(1+.02)}{(1+.16)^3}=.720$$

SPWECH = .030(.914 + .819 + .720 + each succeeding year's value)
SPWECH = .0736 $/kWh

where

SPWECH = the sum of the present worth of energy and operation costs, in dollars per kilowatthour

Appendix B
Example Calculation of Transformer Loss Cost Rates

Assuming the following data, calculate the cost rates for the following:

A. No-Load Losses	NLLCR
B. Load Losses	LLCR
C. Auxiliary Losses	ALCR1 and ALCR2

Availability factor	AF	97%
Average hours per year for stage one cooling, running alone	AHPY1	2000 h
Average hours per year for stage two cooling	AHPY2	1000 h
Booklife	BL	35 yr
Current year energy cost	CYEC	\$0.051/kWh
Efficiency of transmission	ET	95%
Energy cost inflation rate	EIR	5%
Fixed charge rate—generation	FCRG	17%
Fixed charge rate—transformer	FCRT	19%
Fixed charge rate—transmission system	FCRS	18%
Generation installation cost	GIC	\$800/kW
Peak-per-unit load	PUL	1.67
Peak responsibility factor	PRF	0.96
Rate of return	ROR	16%
Increase factor	IF	1.07
Transformer loading factor	TLF	0.5
Transmission system installation cost	SIC	\$200/kW
Capital recovery factor	CRF	17%

A. No-Load Loss Cost Rate:

$$NLLCR = \frac{LIC + LECN}{(ET)(FCRT)(IF)}$$

To determine LIC:

$$LIC = (GIC)(FCRG) + (SIC)(FCRS)$$

$$LIC = (800)(0.17) + (200)(0.18) = 136 + 36 = \$172/\text{kW-yr}$$

To determine LECN:

Transformer users have many different ways of predicting their future energy costs.

In the interest of continuing this example, the following is presented as one way to determine LECN (steps (1) through (4), below, are illustrated in Table A1 of Appendix A):

(1) Determine each year's energy cost in dollars per kilowatthour for the period of time being considered, (e.g., the booklife of the transformer).

(2) Determine the present worth factor for each year, based on the rate of return.
(3) Multiply the energy cost for each year by the present worth factor for that year, to get the present worth of that year's energy cost in dollars per kilowatthour.
(4) Add each of the present worth values for all of the years being considered, to get the sum of the present worth of energy and operating cost in dollars per kilowatthour.
(5) Multiply 8760 hours per year by the availability factor (0.97) to get 8497 hours per year for the operation of the transformer.
(6) Multiply the sum of the present worth in dollars per kilowatthour by 8497 hours per year to get the sum of the present worth of energy and operating cost in dollars per kilowatt-year.
(7) Multiply the sum of the present worth of energy and operating cost in dollars per kilowatt-year by the capital recovery factor to get LECN, the levelized energy and operating cost of no-load losses for the transformer, in dollars per kilowatt-year. For the sake of the present example, assume that LECN was found to be $500 per kilowatt-year.

To continue the example calculation:

$$\mathrm{NLLCR} = \frac{\mathrm{LIC} + \mathrm{LECN}}{(\mathrm{ET})(\mathrm{FCRT})(\mathrm{IF})} = \frac{172 + 500}{(0.95)(0.19)(1.07)} = \$3479\,/\,\mathrm{kW}$$

This is the figure that would be furnished to the manufacturers at the time of soliciting bids, and in the bid evaluation process, each manufacturer's guaranteed no-load losses in kilowatts would be multiplied by $3479 and added to the manufacturer's bid price.

B. Load Loss Cost Rate:

NOTE: LECN was calculated using an availability factor of 0.97. Therefore LECL will be equal to LECN divided by 0.97.

$$\frac{\mathrm{LECN}}{0.97} = \frac{500}{0.97} = \$515.46 \text{ per kW-yr (see 6.1.10)}$$

$$\mathrm{LLCR} = \frac{(\mathrm{LIC})(\mathrm{PRF})^2(\mathrm{PUL})^2 + \mathrm{LECL}(\mathrm{TLF})^2}{(\mathrm{ET})(\mathrm{FCRT})(\mathrm{IF})}$$

$$= \frac{(172)(0.96)(0.96)(1.67)(1.67) + (515.46)(0.5)(0.5)}{(0.95)(0.19)(1.07)}$$

$$= \frac{442.08 + 128.87}{0.193} = \$2958\,/\,\mathrm{kW}$$

This is the figure that would be furnished to the manufacturers at the time of soliciting bids, and in the bid evaluation process, each manufacturer's guaranteed load losses in kilowatts would be multiplied by $2958 and added to the sum of the bid price and the no-load loss values given in A. above.

C. Auxiliary Loss Cost Rate:

$$ALCR1 = \frac{LIC + LAEC1}{(ET)(FCRT)(IF)}$$

LECN, found in A. above, can be converted to LAEC1 by multiplying LECN by the ratio of the total number of hours per year that stage 1 cooling will be running, to the number of hours per year used for finding LECN. (In the present example,

$$LAEC1 \quad = LECN\frac{3000}{8497} = \frac{(500)(3000)}{8497} = \$176.5/\mathrm{kW\text{-}yr.})$$

$$ALCR1 = \frac{LIC + LAEC1}{(ET)(FCRT)(IF)} = \frac{172 + 176.5}{(0.95)(0.19)(1.07)} = \frac{348.5}{(0.95)(0.19)(1.07)}$$

$$= \quad \$1804/\mathrm{kW}$$

$$ALCR2 = \frac{LIC + LAEC2}{(ET)(FCRT)(IF)}$$

LECN, found in A. above, can be converted to LAEC2 by multiplying LECN by the ratio of the total number of hours per year that stage 2 cooling will be running, to the number of hours per year used for finding LECN. (In the present example,

$$LAEC2 \quad = LECN\frac{1000}{8497} = \frac{(500)(1000)}{8497} = \$59/\mathrm{kW\text{-}yr.})$$

$$ALCR2 = \frac{LIC + LAEC2}{(ET)(FCRT)(IF)} = \frac{172 + 59}{(0.95)(0.19)(1.07)} = \frac{231}{(0.95)(0.19)(1.07)}$$

$$= \quad \$1196/\mathrm{kW}$$

When bids are solicited, the values found above should be stated to the manufacturers as follows:

"Losses will be evaluated at the following values:

No-load loss at 100% of rated voltage	—	\$3479/kW
Load loss at self-cooled rating	—	\$2958/kW
Stage one cooling equipment power	—	\$1804/kW
Stage two cooling equipment power	—	\$1196/kW

In the bid evaluation procedure, each loss evaluation figure listed above will be multiplied by its respective guaranteed loss value in kilowatts, and the resulting figures will be added to the bid price to give a total evaluated price for bid comparison."

If the following bids were received, they would be compared as shown below (assume that all four bids represent acceptable transformers with comparable features):

		Guaranteed Losses (kW)			
Manufacturer	Bid Price	No-Load	Load	Stage 1 Cooling	Stage 2 Cooling
A	$225,000	14	45	1	0.5
B	$215,000	15	46	2	1
C	$195,000	18	55	3	2
D	$240,000	13	40	1	0.5

NLLCR = $3479/kW
LLCR = $2958/kW
ALCR1 = $1804/kW
ALCR2 = $1196/kW

evaluated cost = bid price + (NLLCR)(no-load losses) + (LLCR)(load losses) + (ALCR1)(stage one losses) + (ALCR2)(stage two losses)

Mfr. A: $225,000 + (3479)(14) + (2958)(45) + (1804)(1) + (1196)(0.5) = $409,218
Mfr. B: $215,000 + (3479) (15) + (2958)(46) + (1804)(2) + (1196)(1) = $408,057
Mfr. C: $195,000 + (3479)(18) + (2958)(55) + (1804)(3) + (1196)(2) = $428,116
Mfr. D: $240,000 + (3479) (13) + (2958)(40) + (1804)(1) + (1196) (0.5) = $405,949

The offering from Manufacturer D is seen to be the most cost-effective, even though the bid price is the highest.

An analysis such as this should be made to determine the lowest evaluated cost.

IEEE

IEEE

IEEE

IEEE